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Petroleum News

The Utah Geological Survey is a division of the Utah Department of Natural Resources; M. Lee Allison, Ph.D., State Geologist and Director

***Petroleum News** is published by the Utah Geological Survey (UGS) to provide information on U.S. Department of Energy (DOE)-sponsored, UGS-managed projects and energy related topics to petroleum companies, researchers, and other parties involved in exploring and developing Utah's hydrocarbon resources. Tim Madden, editor.*

IN THIS ISSUE

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UGS Garners Funding for Study of Lower Green River Formation

The latest Utah Geological Survey project, *Reservoir Characterization of the Lower Green River Formation, Southwest Uinta Basin*, is a three-year investigation of the subsurface and surface geology of the Green River Formation in the Monument Butte and Roan Cliffs areas of the Uinta Basin. The project will be divided into eight tasks. The first, subsurface correlations, will be accomplished within the first 27 months. The second, surface correlations, will begin six months in and take about 27 months. The third, petrophysics, will begin 12 months in and require 12 months to complete. The fourth, geologic modeling, will be accomplished within the first 33 months. The fifth, hydraulic fracture analysis, will be accomplished within the first 25 months. The sixth, geostatistics and numerical simulation modeling, will require the entire 36 months to complete. The seventh, technology transfer, and the eighth, administration, will be ongoing activities carried out during the entire project period.

The Green River is a Tertiary-aged formation deposited in ancient Lake Uinta which occupied the current Uinta Basin. The Green River intertongues with the Colton Formation, which is dominantly alluvial sediments deposited adjacent to the lake. Over 450 million barrels of oil have been produced from Tertiary sediments in the lower Green River Formation. Most of the production has come from Cedar Rim, Altamont, Bluebell, and Red Wash fields which produce from sediments derived from the Uinta Mountains and deposited along the north shore of Lake Uinta. The southwest region of the Uinta Basin has produced oil from fluvial-deltaic transgressive-regressive cycles containing sediments derived from the south, along the more gently north-dipping southern shoreline facies of Lake Uinta.

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New Study Suggests Flanks of Anticlines May Be Better Targets for Oil and Gas Deposits in GSENM

Igneous activity some 30 million years ago north of what is now the Grand Staircase-Escalante National Monument may have triggered a massive southern movement of carbon dioxide (CO_2), other non-hydrocarbon gases, and deep ground water, which may have displaced oil and gas to the flanks of anticlines in the region, UGS geologists suggest.

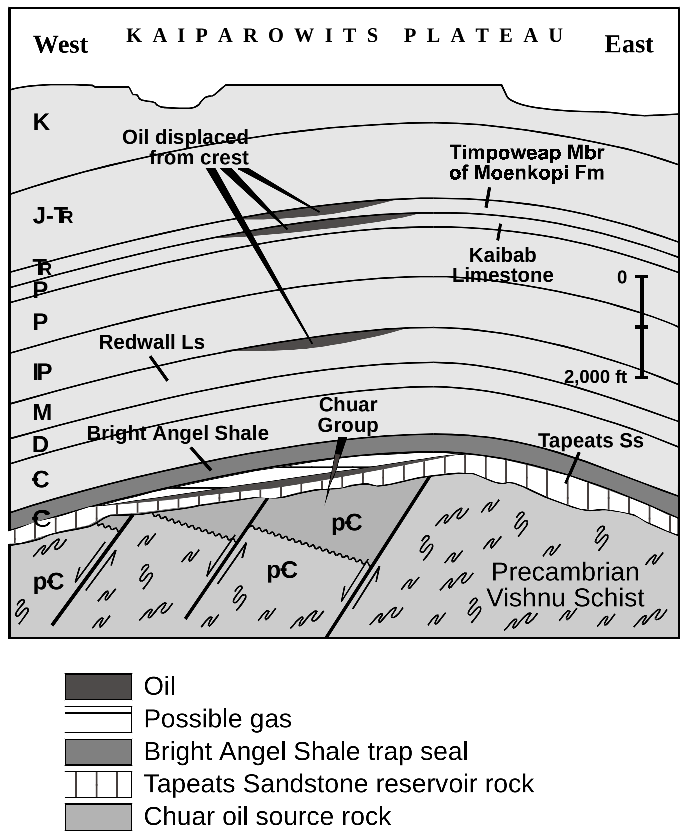
Recent oil exploration efforts in the monument have targeted the 570-million-year-old Cambrian Tapeats Sandstone at depths between 5,000 and 12,000 feet. Evidence of hydrocarbons was found, but not significant oil or gas reservoirs. The new theory suggests that the place to drill is on the flanks of the anticlines, where there may be stacked reservoirs. The Upper Valley oil field, part of which lies within the monument, has produced more than 25 million barrels of oil from just such a reservoir.

The displacement theory was presented at the AAPG annual meeting in Salt Lake City last May by its lead author, Thomas C. Chidsey, Jr., senior scientist and head of UGS's petroleum section. Co-authors are UGS senior geologist Douglas A. Sprinkel and M. Lee Allison, UGS Director and State Geologist. The authors also suggested that the effect of this natural CO_2 flood could have been so dramatic as to have flushed oil deposits completely out of the region and into northern Arizona.

But this theory " does not wipe out the chance of oil in the monument," Allison noted. "It just means you look in different places. We still believe this area is under-explored." Chidsey pointed out that it took 100 wells to find commercial oil and gas deposits in the overthrust belt in northeaster Utah and southwestern Wyoming. To date, there have been 48 exploratory wells drilled within the monument's boundaries — most of them on the crests of anticlines. PN

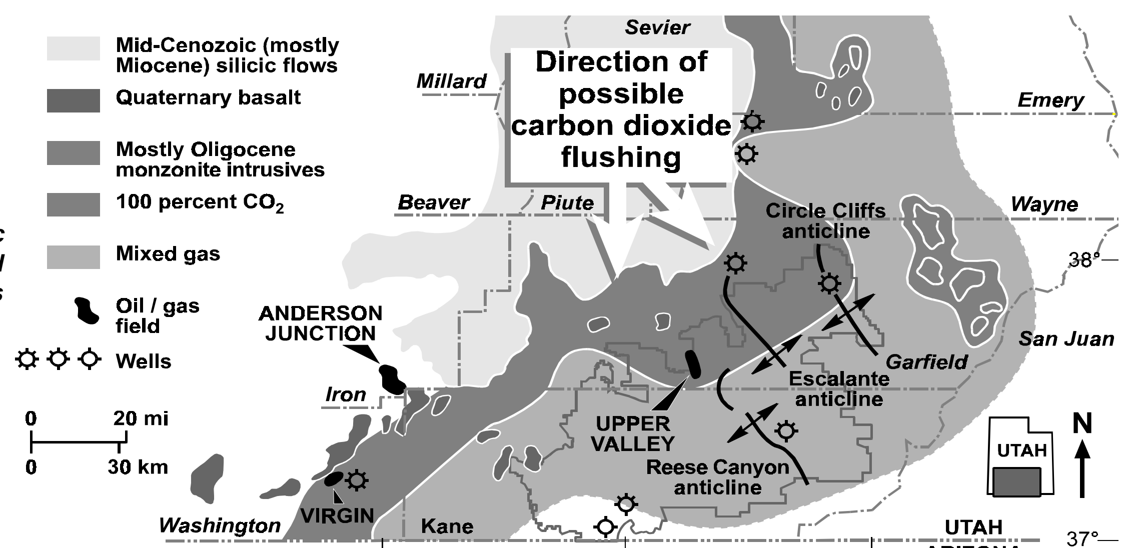
Potential oil and gas traps within the Grand Staircase-Escalante National Monument, showing possible displacement to flanks of anticlines.

Hydrocarbon Traps



Possible Natural Carbon Dioxide Flood

The presence of carbon dioxide and other non-hydrocarbon gases in wells is evidence of hydrodynamic pressure that pushed oil and gas deposits from the crests of anticlines.



Modified from Brandt, 1989

Ferron Sandstone Project Concludes with Popular Field Trip and Examination of Diagenetic History, Geophysical Properties

The goals of the Ferron Sandstone project are to identify the characteristics of an outcrop analog of a fluvial-deltaic reservoir and to create a three-dimensional model that can be used to improve oil-field development in similar reservoirs worldwide. Beginning in 1993, investigators began to quantitatively determine the geological and petrophysical properties of the Cretaceous Ferron Sandstone in east-central Utah. The project reached its concluding phase in 1998 with determinations of the effects of diagenesis on the petrophysical properties of the Ferron Sandstone. In 1998, the project began three final activities: (1) petrophysical analysis, (2) production of the Project Final Report, and (3) technology transfer.

U.S. Department of Energy
Geoscience/Engineering
Reservoir Characterization Program

Project Title
Geological and Petrophysical Characterization of the Ferron Sandstone for 3-D Simulation of a Fluvial-Deltaic Reservoir

Project Manager
Thomas C. Chidsey, Jr.

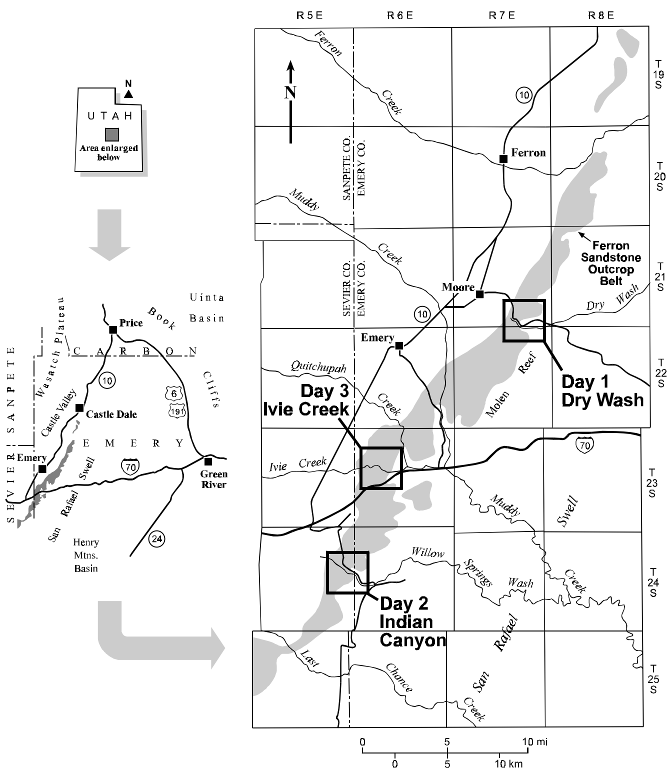
Petrophysical Analysis

This type of subsurface geological interpretation, based on geophysical data or drilling, relies on case studies that examine stratigraphic concepts in the context of transformations that link geological to geophysical variables. The primary goal of a petrophysical analysis is to identify not only the transformations themselves, but what causes them.

An additional objective was to examine the reliability of the common assumption that geophysical properties and relationships observed in outcrop are representative of those existing in the deep subsurface. The investigation showed that the process which generates outcrop exposures — exhumation resulting from uplift and erosion — did indeed overprint patterns of velocity, porosity, and permeability developed in the subsurface, thus challenging the assumption. Petrophysical overprints potentially may result either from diagenetic processes or from mechanical rebound — the rock expansion caused by pressure release. In contrast to most previous studies of diagenetic influences on petrophysical properties, the overprinting here was due to dissolution rather than cementation.

In two field seasons (1994 and 1995), investigators collected a total of 722 oriented-core plugs from the Ferron outcrop. The core samples were 1 to 3 inches long and 1 inch in diameter. Sampling was conducted along more than a dozen near-vertical outcrop traverses. A typical vertical sample spacing of 6.5 to 13 feet targeted all major lithologic units. Petrophysical sampling during the third project year (1996) concentrated on drill cores, particularly those from the Ivie Creek case study drilling program. Eighty-six core plugs and 11 three-dimensional core plug sets were taken from UGS Ivie Creek drill holes 3, 9, and 11. Shale units in these drill cores were unweathered and therefore could be sampled, unlike outcrop shales. Of those samples, both outcrop and drill core, investigators analyzed 471 using the Geoscience Evaluation Module at Amoco.

Thin-section examinations showed that little, if any, primary porosity appears to remain in any of the Ferron outcrop samples. A complex diagenetic history culminated with development of substantial secondary porosity by carbonate dissolution. This secondary porosity is intergranular, not vugular or crack porosity. Petrophysical measurements confirm that decreasing carbonate content is strongly associated with porosity increase. Surprisingly, clay-mineral content has only a minor direct correlation with petrophysical properties.



Location map showing the Ferron Sandstone outcrop belt (shaded) and AAPG annual meeting field trip hike locations.

Ferron porosities in deep wells suggest that pre-

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Ferron Sandstone
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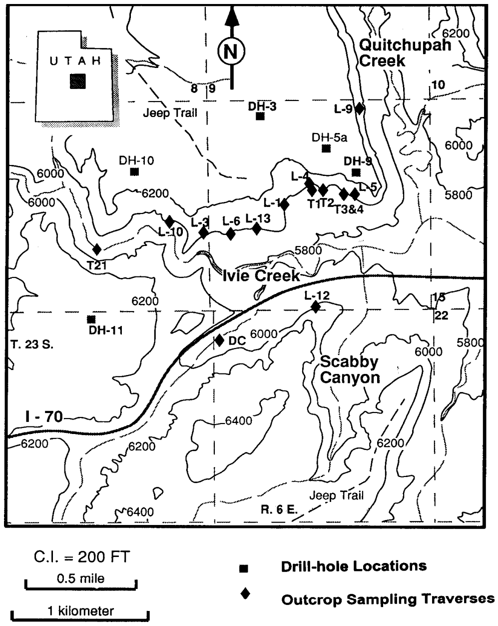
exhumation porosities were 4±4 percent. Porosity increase accelerated as the Ferron was progressively exhumed. By the time portions of the Ferron reached near-surface depths, average porosity had increased to 9.3±2.4 percent, and outcrop samples are even more porous (13.0±0.6 percent). This pattern of secondary porosity development differs from the diagenetic pattern commonly observed in deeply buried, but not exhumed, sandstones: growth of secondary porosity below the depths at which primary porosity is destroyed. The Ferron Sandstone, like sedimentary rocks in several other foreland basins, appears to demonstrate the impact of meteoric water flux on late-stage diagenetic history. Upward meteoric flux provides a combination of high flow rates and cooling-induced increase in calcite solubility that is probably responsible for late-stage carbonate dissolution within the Ferron Sandstone. The patterns of secondary porosity development seen in the study suggest that upward flow along the Ferron beds is pervasive and that this meteoric flow extends to depths of about 1.2 miles.

Whenever exhumation causes development of secondary porosity, then velocity decrease is also expected, because velocity is primarily dependent on porosity. Depth-dependent changes in both velocity and porosity are observed in well logs of the Ferron Sandstone. Cross plots indicate that the velocity drop at depths of <1,800 feet is even stronger than expected from the associated porosity drop. Core-plug measurements indicate that the lithostatic pressure dependence of velocity accounts for these log-based observations of changes in velocity and in velocity/porosity relationship. The lowest pressure core-plug measurements have a velocity/porosity pattern similar to that for shallow (<1,800 feet) log data, and the highest pressure core measurements are consistent with deep log data. Pressure decrease associated with exhumation opened microcracks; laboratory velocity measurements at high pressure close the cracks.



Map of the Ivie Creek case-study area showing location of outcrop sampling traverses and UGS drill holes.

Log analysts often generalize that sonic logs do not detect secondary porosity, particularly vugular porosity in carbonates and fracture porosity. Among sandstones, however, the most common type of secondary porosity is that illustrated by the Ferron logs: intergranular secondary porosity created by dissolution. Ferron core-plug velocity measurements and sonic logs clearly detect this secondary porosity, responding in the same manner as for primary intergranular porosity. Comparison of whole-core and log measurements at UGS drill hole Ivie Creek No. 3 showed consistency for both density and velocity, indicating that these two measurement scales are equally sensitive to microfractures.

Permeability in the Ferron Sandstone is strongly dependent on porosity. The effect of mineralogy on permeability is indirect, associated with the influence of grain size on porosity evolution. Grain size affected the entire diagenetic history of the Ferron Sandstone; the coarsest sands retained the highest permeabilities during

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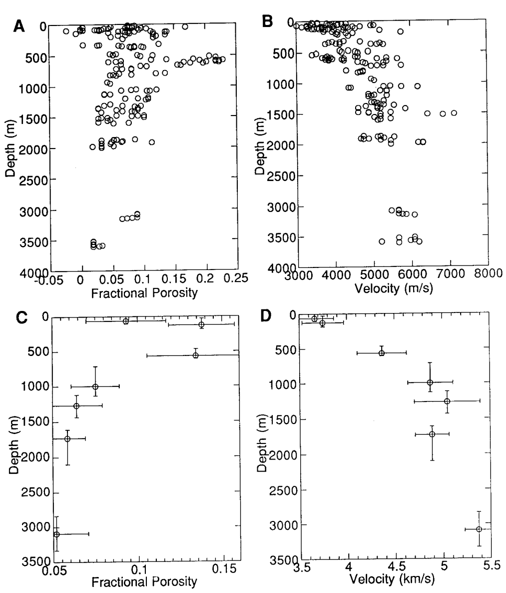


Fractional porosity (A) and velocity (B) of individual Ferron beds, based on well logs from drill holes with locations plotted on map of the Ivie Creek case-study area. Note both the heterogeneity at a given depth and the systematic changes with depth. Variation of average Ferron porosity (C) and velocity (D) with depth, based on three-well adjacent-depth averaging of data from (A) and (B,) respectively.

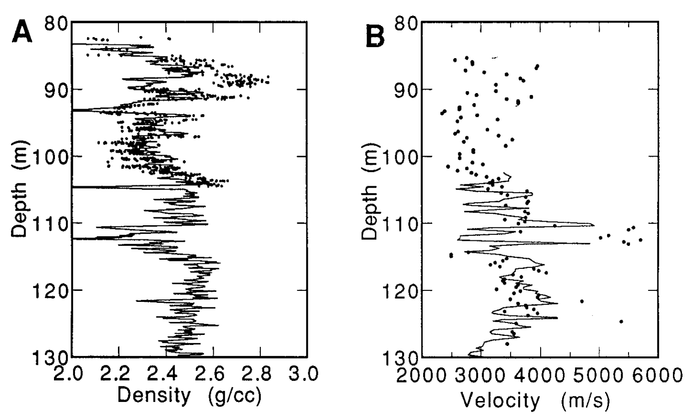


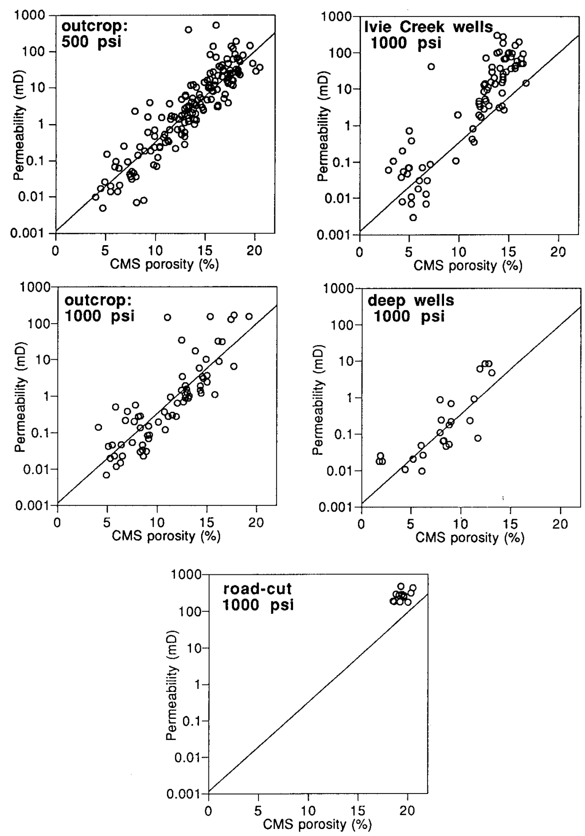
Fig. 3. Comparison of log (line) and core (dots) measurements for density (A) and velocity (B) at UGS drill hole Ivie Creek No. 3.

Ferron Sandstone
continued from page 4

compaction and cementation, and they experienced the greatest permeability enhancement during late-stage expansion of secondary porosity. At the scale of core plugs, permeability anisotropy is relatively minor.

Project Final Report

The final report, which summarizes the research results of the Ferron Sandstone project, is being prepared. The report will include chapters on the: (1) regional stratigraphy, (2) Ferron facies, (3) geological framework of the Ivie Creek, Muddy Creek, and Willow Springs Wash case-study areas, (4) petrophysics and statistical analysis of the Ferron reservoir facies in the Ivie Creek case-study area, and (5) fluid-flow model of the fluvial-dominated Kf-1-Ivie Creek-[a] bedset as a reservoir analog. Cross sections, paleogeographic maps, interpreted photomosaics, measured sections, and permeability and other raw data produced as project deliverables or collected during the course of the project and referred to in the report, will be released by the UGS as open-file or contract reports. The Project Final Report should be published in 1999 and the other reports will be released shortly thereafter.



Porosity/permeability pattern for core-plug samples from the Ferron Sandstone. The reference line is based on linear regression of the 500 psi (atmospheric pressure) outcrop data.

Technology Transfer

The UGS and its partners presented results of the project to the petroleum industry at a three-day field trip and one-day short course during the American Association of Petroleum Geologists annual national meeting in Salt Lake City, Utah, May 17-20, 1998. The pre-meeting field trip and short course were sponsored by the UGS, National Petroleum Technology Office - DOE, Mobil Technology Company, and Amoco Production Company. Field guidebooks and course notes were provided to the 37 attendees

The field trip, titled *Stratigraphic Framework for Reservoir Modeling in Fluvial-Deltaic Deposits: A Parasequence-level Analysis and Reservoir Characterization of the Ferron Sandstone, Utah*, was on May 14-16, 1998. The first day of the trip involved an overview of the Ferron coalbed methane play and an introduction to the Ferron outcrops at Dry Wash. Dry Wash outcrops exhibit a variety of shoreline and fluvial depositional styles. The entire second day was spent examining shoreface and delta-front deposits within three parasequences of the Kf-1 parasequence set in exposures along the walls of Indian Canyon. Most of the third day was spent on outcrops in the Ivie Creek case-study area. The Kf-1 there includes fluvial-dominated deltaic deposits (clinoforms) in a well-defined subdelta lobe. Overlying shoreface and wave-dominated deposits of Kf-2 were also examined. Prior to the excursion, field trip leaders used water-soluable markers to indicate permeability values on the outcrops along sections traversed by the group.

The short course, titled *Core and Reservoir Modeling Workshop: Fluvial-Deltaic Nearshore Sands of Ferron Sandstone,* was held on May 17, 1998. The course took the participants from outcrop to reservoir modeling and flow simulation results of the Ferron project. The course began with a brief review of the stops and geologic settings of the field trip mentioned above. The morning was devoted to examining core, corresponding geophysical logs, and core permeability data to identify sand trends/facies, relate facies to permeability, and classify bounding surfaces. Correlation exercises helped participants understand the challenges involved in working with a subsurface data set, while enjoying the benefit of three-dimensional outcrop exposures. In the afternoon, methods were outlined to quantify the outcrop data, build two- and three-dimensional petrophysical models, and simulate different reservoir production scenarios. Petrophysical and architectural data collected at the Ferron Sandstone study site were incorporated in project reservoir simulations that will aid in exploring the impact of clinoform architecture on fluid flow through a fluvial-dominated deltaic deposit. The simulation results provide direct insight into the way features observed in outcrop might influence reservoir production strategies. The detailed simulation models presented during the course also provide a basis for evaluating how such features might be treated in the upscaling methods needed to create the coarser simulation grids used in evaluating reservoir performance.

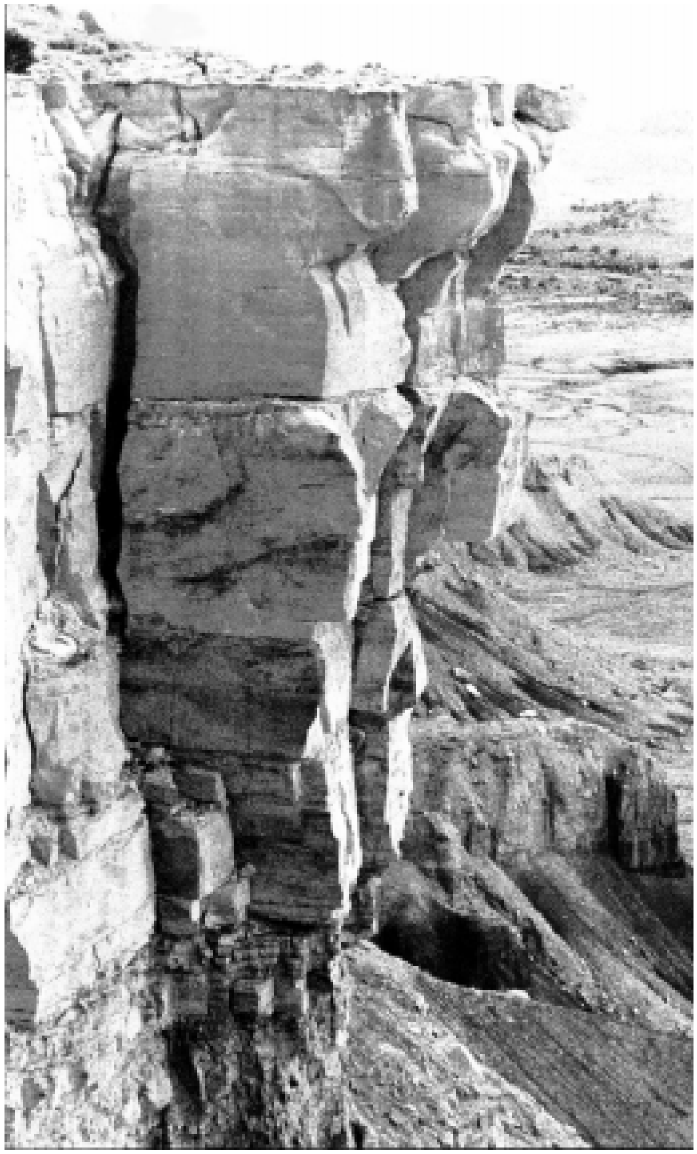
Project material was displayed at the UGS booth during the AAPG annual convention. Ferron team members presented a paper describing reservoir modeling and flow simulation of the Ferron Sandstone at the convention. The project home page on the UGS Internet web site **(http://www.ugs.state.ut.us/ferron.htm)** was updated with the latest quarterly technical report and project publications list. **PN**

Proposed Annual Ferron Sandstone Field Trip and Core Workshop

The UGS is considering offering an annual field trip and core workshop on the Ferron Sandstone. If you, or anyone you work with, are interested, please contact Tom Chidsey at (801) 537-3364 or via e-mail at **nrugs.tchidsey@state. ut.us** or Tim Madden at (801) 537-3306, e-mail **nrugs.tmadden@state. ut.us**.

At the 1998 American Association of Petroleum Geologists meeting in Salt Lake City, the Ferron Sandstone field trip and core workshop, hosted and sponsored by the UGS, were very popular. Many participants asked whether the UGS would be willing to repeat the events, perhaps to be offered at about the same time as the annual AAPG meeting. If there is enough interest among *Petroleum News* readers and others, the UGS will make the arrangements.

The main Ferron Sandstone cliffs and deeply incised canyons provide a three-dimensional view of variations and transitions in oil and gas reservoir facies analogs *(see accompanying photograph)*. The Ferron Sandstone has excellent exposures along depositional strike; numerous canyons that cut perpendicular to strike offer excellent exposures along the depositional dip direction.



Ferron Sandstone Outcrop, Utah

The proposed three-day field trip and core workshop have two goals: (1) review the regional stratigraphy and (2) provide detailed reservoir characterization of various fluvial-deltaic depositional environments and associated permeability trends. The first goal allows a detailed interpretation of the regional stratigraphy of the fluvial-deltaic Ferron Sandstone outcrop belt and shows how the regional morphological framework can be incorporated into model simulations at the oil and gas field scale. The dimensions and character of a variety of architectural elements of a fluvial-deltaic depositional system are well displayed at various stops. Participants will observe the complexities of the application of sequence stratigraphy to these rocks as well as a large variety of reservoir elements that are superbly exposed. As the presentation develops, participants will see how various stratigraphic units may be considered as large-scale reservoir blocks, isolated from one another by marine and/or delta-plain shales. Participants will have the opportunity to see bounding surfaces (fluid-flow barriers or baffles), and their related geometries in several depositional environments and compare these with similar surfaces found in coal. All these characteristics make the Ferron Sandstone a world-class analog for fluvial-dominated deltaic oil and gas reservoirs.

We will achieve our second goal by developing a detailed sedimentological characterization of the facies in the Ivie Creek area just north of Interstate 70. This case-study area at Ivie Creek was selected because of abrupt facies changes in two parasequence sets (Kf-1 and Kf-2). The first, Kf-1, is represented by a fluvial-dominated delta deposit and changes from proximal to distal from east to west and was the focus of geologic and permeability characterization during the DOE-sponsored UGS Ferron project. The second, Kf-2, represents a wave-modified deltaic deposit consisting of lower, middle, and upper shoreface, foreshore, and mouth-bar environments of deposition. Facies of this type are common in deltaic reservoirs worldwide. Participants will see how variations in facies influence both compartmentalization and permeability, and they will examine the major reservoir types (mouth-bar complex, wave-modified and fluvial-dominated delta front, distributary channel, and tidal deposits) associated with the Ferron Sandstone.

The core workshop, to be held in the UGS Sample Library, will be devoted to examining Ferron core, corresponding geophysical logs, and core permeability data to identify sand trends/facies, relate facies to permeability, and classify bounding surfaces. Correlation exercises will help participants understand the challenges involved in working with a subsurface data set, while enjoying the benefit of three-dimensional outcrop exposures. PN

Paradox Project Completes Economic Assessments, Reserve and Recovery Determinations

The primary objective of this project is to enhance domestic petroleum production by demonstration and technology transfer of an advanced oil recovery technology in the Paradox basin, southeastern Utah. If this project can demonstrate technical and economic feasibility, the technique can be applied to about 100 additional small fields in the Paradox basin alone, and result in increased recovery of 150 to 200 million barrels of oil.

This project was designed to characterize five shallow-shelf carbonate reservoirs in the Pennsylvanian (Desmoinesian) Paradox Formation and choose the best candidate for a pilot demonstration project for either a waterflood or carbon dioxide (CO_2) flood project. Phase 1 was completed August 31, 1998. Phase II began on September 1, 1998, and will run through August 31, 2002. With the completion of Phase I, investigators completed reservoir characterizations and simulations, economic assessments, and recommendations for Phase II, which will be a pilot CO_2 flood field demonstration and related technology transfer activities. The field demonstration, monitoring of field performance, and associated validation activities will take place in the Paradox basin within the Navajo Nation.

This project is managed by the UGS and funded under the Class 2 Oil Program of the National Petroleum Technology Office, DOE, Tulsa, Oklahoma. Harken Southwest Corporation, Irving, Texas, is the industry partner. Additional support comes from the Utah Office of Energy and Resource Planning.

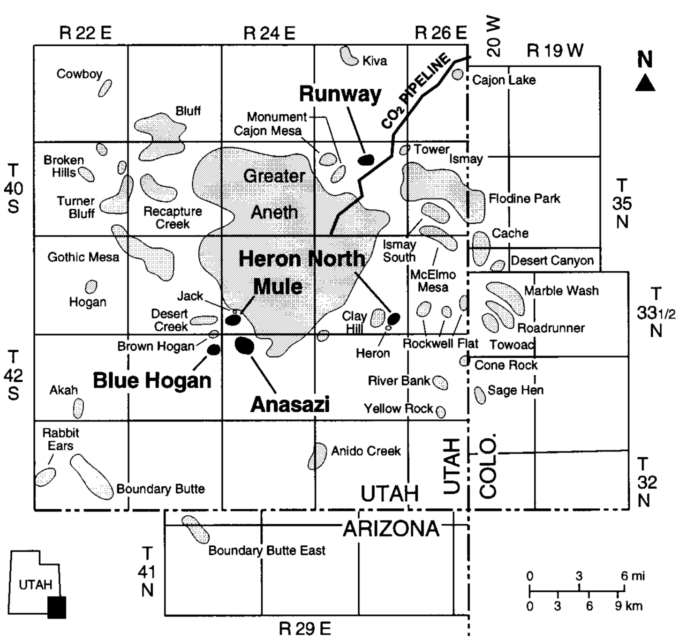


Figure 1. Location of project fields (dark shaded areas with names in bold type) in southwestern Paradox basin on the Navajo Nation, San Juan County, Utah

U.S. Department of Energy
Class 2 Oil Program

Project Title
Increased Oil Production and Reserves Utilizing Secondary/Tertiary Recovery Techniques on small Reservoirs in the Paradox Basin, Utah

Project Manager
Thomas C. Chidsey, Jr.

Summary of Technical Progress

Two activities were completed as part of the geological and reservoir characterization of five productive carbonate buildups in the Desert Creek zone of the Paradox Formation of the Paradox basin, San Juan County, Navajo Nation, Utah (figure 1): (1) economic assessments of reservoir CO_2 floods and recommendations, and (2) reserve and recovery determinations.

Economic Assessments of Reservoir CO_2 Floods and Recommendations

Summary

The principal objectives of the study were to develop detailed quantitative descriptions of shallow-shelf carbonate buildups (algal mounds) and use these descriptions, coupled with composition simulation, to predict the performance of the reservoirs in the mound complexes under three different reservoir recovery processes. The three processes are: primary depletion, CO_2 flooding, and waterflooding. The economic feasibility of implementing one or more recovery processes was also investigated.

Compositional simulation studies were conducted for Anasazi and Runway fields (figure 1). The results indicate that CO_2 flooding is the only technically feasible recovery process suitable for these reservoirs. Based on this conclusion, CO_2-flood implementation costs were developed. Implementation costs in conjunction with reservoir performance production and injection predictions were used to complete a suite of economic assessment studies. One of the CO_2-implementation options studied provided the best economic return: a continuous CO_2-injection case utilizing re-injection of unprocessed produced gas, a leased main injection compressor, and DOE cost share, provided a before-tax net present value (NPV) discounted at 10 percent per year of more than $5.9 million and before-tax rate of return (ROR) of 32 percent on a total investment of $2.7 million for Anasazi field. The profitability index (PI) of this particular implementation was determined to be 10.4 to 1.0. For Runway field, before-tax NPV discounted at 10

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Paradox Project

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percent per year would be more than $3.1 million with a before-tax ROR of 30 percent on a total investment of $2.79 million. The PI of this particular implementation was determined to be 5.0 to 1.0.

The study results on predicted CO_2-flood responses and the associated economics, support the extension of the overall shallow-shelf carbonate evaluation program to Phase II. Phase II involves the implementation and completion of a CO_2 flood in the Anasazi or Runway reservoirs.

Economic Assessment of CO_2 Flood Anasazi Field

Using reservoir-simulation-based performance predictions and current CO_2-flood implementation costs, detailed economic assessments were conducted for a number of different CO_2-flood options. These sets of studies indicated that:

1. A CO_2 flood of the Anasazi reservoir has robust economics. With DOE participation the project would have a ROR of 62 percent, a payout of 35 months, a PI of 15 to 1, and a discounted (10 percent) NPV in excess of $12.5 million. Even without DOE participation the economics remain robust with a ROR of 48 percent, a payout of 39 months, a PI of 8 to 1, and a discounted NPV of over $11.0 million. The capital requirements would be $3.146 million.
2. Leasing the compressor on a five-year contract basis is better economically than purchasing the compressor. Leasing improves the ROR by approximately $1.0 million.
3. The benefit from separating CO_2 from hydrocarbons in produced gas and using the hydrocarbons for fuel and sales is offset by the large capital investment required for a membrane separation facility. Thus, re-injection of all produced gas without processing is economically more attractive than implementing a CO_2 flood with gas processing.
4. The difference between a minimum and maximum cost option for installation of flow/injection lines and the CO_2 supply is approximately $1.0 million; however, the economics are still robust. With DOE cost sharing, the ROR is 56 percent with a PI of 11.5 to 1.
5. The ROR and PI are not significantly different for

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TABLE 1

Cumulative Production from Project Fields

Project Field	Cumulative Production*		
	Oil (bbl)	Gas (MCF)	Water (bbl)
Anasazi	1,855,126	1,581,621	29,335
Blue Hogan	306,468	295,821	1,874
Heron North	206,446	328,713	34,820
Mule	399,887	260,138	29,250
Runway	794,669	2,620,789	5,505

As of July 1, 1998, Utah Division of Oil, Gas and Mining

TABLE 2

Reserve and Recovery Determinations

Project Field	OOIP* (MSTB)	Primary Recovery		ROIP** (MSTB)	CO_2 Flood Projected Recovery (MSTB)	CO_2 Flood Recovery % ROIP
		Oil (MSTB)	Gas (MCF)			
Anasazi†	4,706	2,000	1,890,000	2,706	2,208	81.6
Blue Hogan	2,530‡	321	968,000	2,209	1,586	71.8
Heron North	2,640‡	216	2,650,000	2,424	1,740	71.8
Mule	2,000‡	454	288,000	1,546	1,110	71.8
Runway	3,372	825	2,830,000	2,547	1,577	61.9

* *Original oil in place (thousand stock tank barrels [MSTB]), mound-core and supra-mound intervals (includes platform interval in Runway)*

** *Remaining oil in place*

† *High rate case starting CO_2 flood January 1, 2000*

‡ *Estimate based on approximate volumetric data*

Paradox Project

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a process using blowdown after six years of CO_2 injection versus the continuous CO_2 injection case. However, the NPV is substantially less with blowdown (approximately $1.4 million). The lower NPV is a result of lower oil recovery for the blowdown case (800,000 stock tank barrels [STB] less than the continuous injection case).

Production data and injection gas requirements, including CO_2 make-up purchases, were used to assess, from an economic standpoint, the financial merits of CO_2 flood with an 8 million cubic feet of gas per day total injection rate commencing January 1, 2000. The economic assessment, using two compressor options, was conducted assuming the following conditions: (1) leased compressor (option 1 - $19,500/option 2 - $23,500 [same compressor with a different engine]), (2) CO_2 supply line construction using the minimum costs option ($825,000), (3) no gas processing, and (4) cost sharing by DOE. This assessment demonstrates that CO_2 flooding provides both an adequate flood response with either of the compressor options, an acceptable economic ROR of 32 percent, and a payout of 36 months. A discounted (10 percent) NPV of $5.9 million could be realized by implementing a CO_2 flood under the proposed conditions.

In summary, if the CO_2 flood performs as predicted, it is a financially robust process for increasing the reserves of the Anasazi reservoir; however, the ROR and NPV are very sensitive to oil prices (figures 2 and 3). Therefore, economics should be re-run before installation of injection facilities.

Recommendations

Based on the results of the completed geologic study, reservoir performance predictions, and the associated economic assessment of implementing a CO_2 flood in the Anasazi reservoir, the following production scenario is recommended:

1. A CO_2-injection project should be implemented in the Anasazi reservoir.
2. A field injectivity test using CO_2 should be conducted on the Anasazi No. 6H-1 well, a project well in the western part of the field, to establish long-term injection rate data before committing to further Phase II work.
3. After the CO_2 source is obtained for Anasazi field, economics should be re-run to see if the project is still economically feasible at current prices.
4. The main injection compressor should be leased rather than purchased to provide the most operating flexibility and least financial risk.
5. Produced gas processing is not required for a single-field CO_2-flood implementation case. It is not required from a reservoir processing standpoint nor is it justified economically.
6. Horizontal well injectivity should be predicted from the appropriate well-test models after calibration with vertical well-test data.

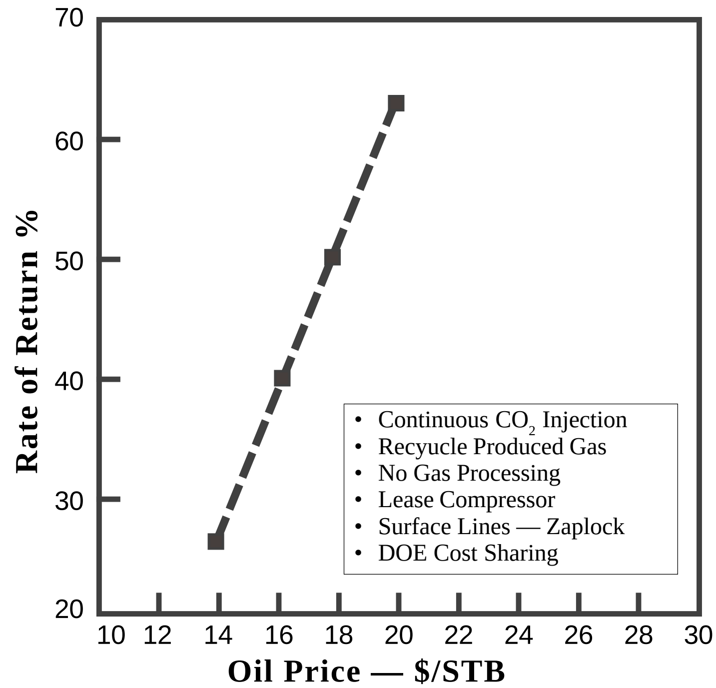

Figure 2. Rate of return versus price of oil, Anasazi field CO_2 flood at high rate

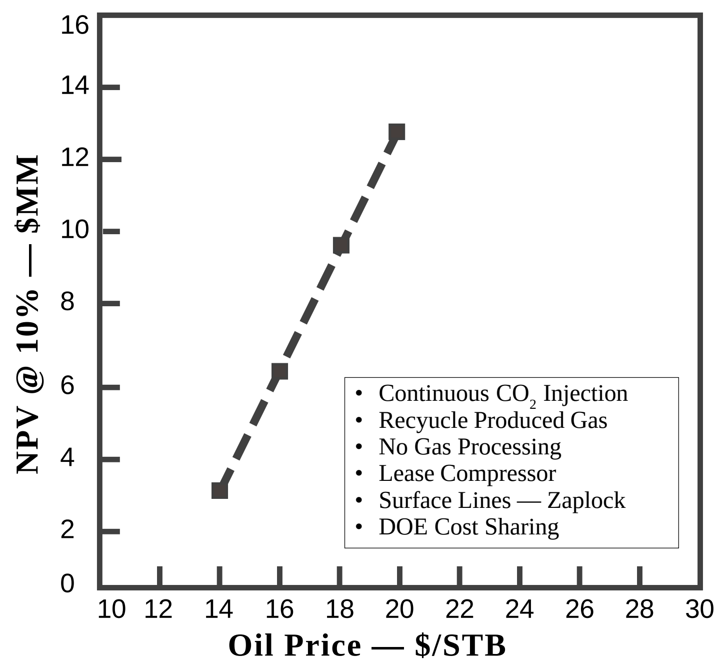

Figure 3. Net present value versus price of oil, Anasazi field CO_2 flood at high rate

Economic Assessment of CO_2 Flood Runway Field

Using reservoir-simulation-based performance predictions and current CO_2-flood implementation costs, detailed economic assessments were conducted for five different CO_2-flood options. This set of studies indicated that:

1. A CO_2 flood of the Runway reservoir has acceptable economics. With DOE participation the project would

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have a ROR of 30 percent, a payout of 32 months, a PI of 5 to 1, and a discounted (10 percent) NPV in excess of $3.1 million. Even without DOE participation the economics remain acceptable with a ROR of 21 percent, a payout of 39 months, a PI of 2.8 to 1, and a discounted NPV of almost $2.0 million. The capital requirements would be $2.789 million.

2. Based on the Anasazi study, leasing rather than purchasing a compressor was adopted for the Runway evaluation.

3. The difference between a minimum and maximum cost option for installation of flow/injection lines and the CO_2 supply is approximately $233,000, making the economics still acceptable. With DOE cost sharing, the ROR is 29 percent with a PI of 4.8 to 1, and a discounted NPV of $2.9 million.

4. Most economic evaluations show negative cash flows in the year 2008, when operating costs exceed revenues. At this point the projects were terminated. However, the reservoir process should have been changed from continuous CO_2 injection to blowdown and the economics re-run. The additional recovery from blowdown, without the operating costs associated with CO_2 injection, would improve economic returns. Thus, additional prediction runs should be completed to assess the economic effect of conversion to blowdown.

If the CO_2 flood performs as predicted, it is a financially acceptable process for increasing the reserves of the Runway reservoir. As in the Anasazi field, the ROR and NPV are very sensitive to oil prices (figures 4 and 5).

Recommendations

The recommendations for Runway are the same as for the Anasazi field. With economic evaluations using a $20/bbl oil price of a CO_2 flood in the Runway field, the production scenario is similar:

1. A CO_2-injection project should be implemented.
2. A field injectivity test using CO_2 should be conducted on a Runway well to establish long-term injection rate data before committing to further Phase II work.
3. After the CO_2 source is obtained for Runway field, economics should be re-run to see if the project is still economically feasible at current prices.
4. The main injection compressor should be leased rather than purchased to provide the most operating flexibility and least financial risk.
5. The economic trade-off of shutting in producers during reservoir fill-up versus continued production during fill-up should be assessed.
6. Horizontal well injectivity should be predicted from the appropriate well-test models after calibration with vertical well-test data.

Conclusions

Budget Period I of the project showed that a CO_2 flood was technically superior to a waterflood and was economically feasible. For Anasazi field, an optimized CO_2 flood is predicted to recover 4.21 million STB of oil. This represents an increase of 1.65 million STB of oil over predicted primary depletion recovery by January 1, 2012. The projected 4.21 million STB of oil production represents about 90 percent of the original oil in place (OOIP) in the mound complex and 37 percent of the OOIP of the total system modeled. For Runway field, the best CO_2 flood is predicted to recover 2.4 million STB of oil. This represents

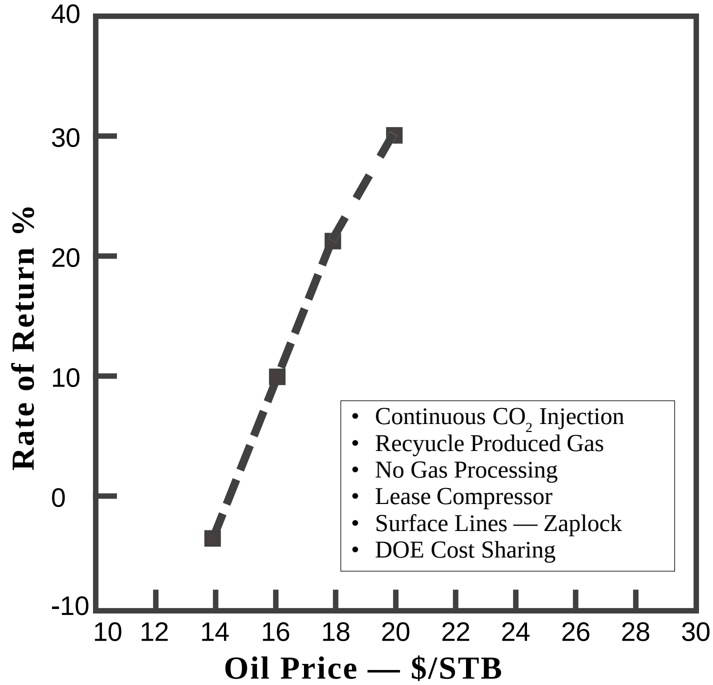

Figure 4. Rate of return versus price of oil, Runway field CO_2 flood at high rate

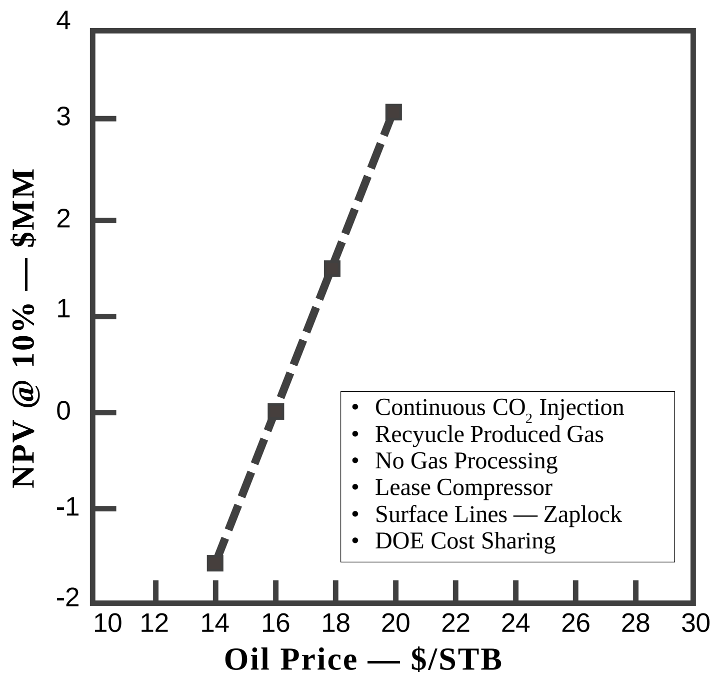

Figure 5. Net present value versus price of oil, Runway field CO_2 flood at high rate

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Paradox Project
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an increase of 1.58 million STB of oil over predicted primary depletion recovery by January 1, 2012. The projected 2.4 million STB of oil production represents 71 percent of the OOIP in the mound complex and 48 percent of the OOIP of the total system modeled, excluding the Ismay zone above the Desert Creek zone.

The UGS has recommended continuation of the project into Budget Period II with a field demonstration of the technique on either the Anasazi or Runway field. The field demonstration will include: conducting a CO_2 injection test(s), obtaining a CO_2 source and fuel gas for the compressor, re-running project economics, drilling a development well(s) (vertically or horizontally), purchasing and installing injection facilities, monitoring field performance, and validation and evaluation of the techniques. These activities will take place within the Navajo Nation, San Juan County, Utah.

The demonstration will prove (or disprove) CO_2-flood viability and thus help determine whether the technique can be applied to the other small carbonate-buildup reservoirs in the Paradox basin. The financial impact of simultaneous or sequential flooding of a series of reservoirs should also be assessed. This will quantify the upside potential of CO_2 flooding for the entire basin from both a reserves and an economic standpoint. The experience gained in matching historic production and predicting the performance of the Anasazi and Runway reservoirs indicates that the overall mound geometry and internal facies architecture are critical to matching and predicting performance. Thus, each mound will likely require an individual reservoir study to quantify its CO_2-flood potential and identify the appropriate implementation strategy to maximize oil recovery.

Reserve and Recovery Determinations

The cumulative production for the five project fields as of July 1, 1998, is summarized in table 1. Heron North field is currently shut-in. Primary recovery and OOIP (table 2) were determined from volumetric reserve calculations, material balance calculations, and decline curve extrapolations as well as refined geologic characterization. These volumetric calculations were made by evaluating well logs and reservoir aerial extent (as defined by seismic reflection data) coupled with reservoir geometry. Material balance and decline curve calculations utilized the production and pressure history. Knowing the OOIP and the primary recovery, the amount of oil left behind was calculated. Lastly, utilizing the results from the simulation studies of Anasazi and Runway fields, sweep efficiencies for CO_2 flooding and the ultimate enhanced recovery were estimated for all project fields (table 2). Using the average predicted oil recovery of 71.8 percent (percent recovery of remaining oil in place after primary recovery) for the Runway and Anasazi reservoirs, the projected addition to reserves if CO_2 is also applied to project fields is over 8.2 million STB of oil.

Technology Transfer

Information concerning the Paradox project was disseminated in several forums. An article was published in *Survey Notes* (UGS news magazine) highlighting the successful completion of a horizontal well in Mule field. At the end of 1998, Petroleum Information/Dwights LLC published “Pennsylvanian Carbonate Buildups, Southern Paradox Basin: New Opportunities for Increased Reserves” as part of its *Petroleum Frontiers: A Quarterly Investigation into the Most Promising Petroleum Horizons and Provinces* series, volume 15, number 4. A summary of this paper was included in the Four Corners Edition of *Petroleum Information,* volume 72, number 3, January 6, 1999.

The *Oil & Gas Journal* is scheduled to publish “Anasazi Field, Paradox Basin, Utah: The Case for Secondary Recovery from Phylloid-Algal Carbonate Mounds.” The article will focus on Anasazi field reservoir characterization and CO_2 flood simulation results and implications for similar fields in the Paradox basin.

The AAPG published “Pennsylvanian Reserves in Heterogeneous, Shallow-Shelf Reservoirs” in the E & P Notes section of the *Bulletin*, volume 83, number 20, February 1999. The article describes the facies and reservoir characteristics of the project fields, and the Anasazi field modeling and simulation results. An abstract by Tom Chidsey and David Eby, *Diagenetic Characterization of Shallow-Shelf Carbonate Reservoirs, Pennsylvanian Paradox Formation, Southern Paradox Basin, Utah*, was accepted for the AAPG Annual Convention in San Antonio, Texas, April 11 - 14, 1999. The presentation will be part of the AAPG poster session on upper Paleozoic carbonate mound reservoirs on Monday, April 12. In addition, information on the Paradox project will be available at the UGS booth in the exhibition hall throughout the conference. Both poster presentations and booth displays will also be featured at the AAPG Rocky Mountain Section Meeting in Bozeman, Montana, August 8 - 11, 1999.

The Paradox project was featured at the UGS Sample Library Open House, October 6, 1998, where project posters and drill core were exhibited; at a conference on fractured reservoirs co-hosted by the UGS and the Petroleum Technology Transfer Council, Rocky Mountain Region, on October 23, 1998, as a booth display; at the annual meeting of the Interstate Oil and Gas Compact Commission in Salt Lake City December 6-8, 1998, as a booth display; and in an oral presentation by David Eby at the Utah Geological Association monthly meeting on January 11, 1999.

Quarterly updates on the project are also displayed on the Paradox home page, which can be reached through the UGS Internet web site at **http://www.ugs.state.ut.us/paradox.htm.** PN

Demonstration Nearly Completed in Bluebell Field

A research team headed by the Utah Geological Survey conducted a reservoir characterization study and field demonstration program of the Bluebell field, Uinta Basin, Utah, under the auspices of the U.S. Department of Energy's National Petroleum Technology Office, Class I Field Demonstration Program.

U.S. Department of Energy
Class 1 Oil Program

Project Title
Increased Oil Production and Reserves from Improved Completion Techniques in the Bluebell Field, Uinta Basin, Utah

Project Manager
Craig D. Morgan

Overview

The Bluebell field produces hydrocarbons from the Tertiary-aged Green River and Colton Formations. The productive interval consists of thousands of feet of interbedded fractured clastic and carbonate beds deposited in a lacustrine environment. Wells have traditionally been completed by perforating 40 or more beds in 1,000- to 3,000-vertical-foot intervals, then acid stimulating the entire interval. This technique is believed to leave many potentially productive beds damaged or untreated.

Objective

The Bluebell study seeks ways to increase primary oil production by improving completion techniques. While the Bluebell field has produced large amounts of oil, indications are that significant reserves remain untapped due to a lack of detailed understanding of the reservoir properties and the current inefficient completion practices.

The UGS-led research team developed a three-well demonstration to test two different completion techniques on older wells and then select one of the methods for use in completing a new well. The Michelle Ute 7-1 well recompletion, the first demonstration, was intended to be a three-stage, high-diversion, high-pressure acid treatment. Each stage consisted of a 500-foot vertical interval with more than 10 beds perforated in each interval. The Malnar Pike 1-17A1E well recompletion, the second demonstration, was an acid treatment at the bed scale, designed to isolate and treat four individual beds. The third demonstration was the staged completion of the newly drilled John Chasel 3-6A2 well.

Two of the demonstrations, Michelle Ute and Chasel wells, were severely hampered by mechanical problems. The Malnar Pike demonstration did improve the oil-production rate from the well, but the recompletion results were not significantly better than from traditional recompletion methods. Although disappointing, the results do provide some insight into the reservoir behavior and could lead to improved methods.

Recompletion of the Michelle Ute 7-1 Well

The Michelle Ute recompletion was intended to be a three-stage acid fracture treatment. Each stage was to be about 500 vertical feet involving the treatment of the previously perforated beds as well as several new perforated beds. Dual-burst thermal decay (TDT) time and dipole shear anisotropy logs were used to identify beds for perforating. The operator treated the entire 1,500-foot interval from one packer seat rather than the three-stage technique as planned because the tubing had a leak. The tubing parted when the operator attempted to come out of the hole after the acid treatment, resulting in several days of fishing with the spent acid left in the formation. Isotope tracer logs run after the treatment showed that only the upper 500 feet of the 1,500-foot interval received any significant acid. As a result, the well had only a minor increase in the daily oil rate, and this declined to the pre-treatment rate in just a few months.

Recompletion of the Malnar Pike 1-17 Well

The Malnar Pike recompletion involved isolation, stimulation, and testing of intervals of less than 500 vertical feet, treating at the bed scale, or as close to bed scale as was practical. The intervals were isolated using a bridge plug at the base and a packer at the top of the test interval. To identify beds for treatment, testing, and post-treatment evaluation, investigators used TDT, dipole shear anisotropy, and isotope tracer logs.

The operator applied four separate treatments. The first two resulted in fluid communication above and below the test interval. The third and fourth were mechanically sound. Based on limited swab testing, the operator believed the first two test intervals were producing water. Therefore, a bridge plug was set above the first two test intervals so that only the third and fourth test intervals and some previous perforations are contributing to the production. The well production rate increased from about 20 barrels of oil per day (BOPD) to about 35-40 BOPD. It is believed that the increase is from the third and fourth test intervals.

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Bluebell Project
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Completion of the John Chasel 3-6A2 Well

The completion of the John Chasel 3-6A2 well was the third step in the three-well demonstration. Quinex Energy Corporation drilled the well to a total depth (TD) of 15,872 feet in the Flagstaff Member of the Green River Formation. After being logged and perforated, the well was stimulated with two separate acid treatments, but poor quality cement and a partial collapse of the casing forced the abandonment of the Flagstaff reservoir. The operator is currently attempting a completion in the overlying Colton Formation. The well is the second deep well in the section, and like most second wells it appears to penetrate partially depleted reservoir rock. The well encountered numerous oil and gas shows in the Green River and Colton Formations, but was drilled to TD with a maximum mud weight of 11 pounds per gallon (lbs/gal). In this part of the Bluebell field the first wells typically required 14 lbs/gal drilling mud, indicating that reservoir pressure has been depleted by the first well drilled in the section.

Most wells in the Bluebell field are completed by perforating 40 to 60 or more beds. Perforations are usually selected based on drilling shows with minor reliance on geophysical well logs. The objective for the Chasel well was to use geophysical well logs to select fewer beds for completion, thus reducing completion costs, increasing the production rate, and greatly reducing the volume of water produced. The TDT log was the primary tool used for selecting perforations. Fracturing identified on the dipole shear anistropy log and exceptional drilling shows were also considered. The density-neutron porosity log was evaluated but log porosity was not a deciding factor.

The Chasel well was completed by acidizing the perforations in two separate treatments. The first treatment was of the lower 12 perforated beds, and the second treatment was of all 19 perforated beds. The isotope tracer log indicated that most of the acid went into perforated and nonperforated beds from 15,130 to 15,340 feet. The log showed extensive communication behind the casing in this interval. Limited swab testing recovered acid water and no oil. Based on this limited test the operator believed the well was producing water. The interval, which included perforated beds 8 through 19, was cement squeezed. The cement tagged at 14,172 feet was drilled out. Beds 8, 13 through 17, and 19 were reperforated; beds 1 through 7 were below the cement, resulting in a total of 14 beds left open to the wellbore.

The operator began swab testing the well after acid treating the interval but the tubing had to be pulled because it was plugged with cement chips. While the tubing was out of the hole the well began to flow. The well initially flowed 124 barrels of oil (BO), 255 thousand cubic feet of gas (MCFG), and no water, and the next day it flowed 133 BO, 125 MCFG, and no water. The operator eventually stopped the flow and ran the tubing back into the hole, discovering that the casing was partially collapsed. Later, while swedging a tight spot the swedge and some of the tubing became stuck in the hole. The operator was unable to retrieve or mill up the fish and that portion of the hole had to be abandoned. The operator is currently attempting a completion in the Colton Formation above the fish.

Conclusions and Recommendations

Fluid communication above and below the test intervals was a major problem in the Malnar Pike well. Both the Michelle Ute and Malnar Pike wells have numerous perforations that have been acidized several times, increasing the potential for communication behind the casing. It is very likely that conventional acid treatments (typically a 500- to 1,500-foot interval) of older wells in the Bluebell field will result in a similar problem. Much of the acid may be moving vertically through the cement and not into the formation.

Test results generally confirmed the interpretation of the anisotropy and TDT logs. Beds with fractures indicated in the anisotropy log generally took most of the acid while beds without fractures took little to no acid. The low treating pressure in both the Michelle Ute and Malnar Pike wells was probably not high enough to hydraulically induce new fractures. Based on the experience of other operators in the Bluebell field, the multi-staged completion technique may be the most effective method for new wells and recompletion of older wells. But after a well has been recompleted numerous times the cost-effectiveness of continuing to do large multi-stage treatments rapidly decreases. At that point the smaller bed isolation recompletion technique as was used in the Malnar Pike well may be more cost effective.

The following recommendations should be considered to effectively use the bed isolation completion technique on wells in the Bluebell field (based on the experience of the Malnar Pike demonstration):

1. set both the packer and bridge plug between perforated intervals that are at least 50 feet apart to reduce the risk of fluid communication,
2. use the anisotropy and TDT logs and select beds that are fractured and have relatively low water saturation, and
3. use a treating pressure high enough to fracture the formation, especially if the anisotropy log indicates that some of the beds being treated do not have fractures.

Technology Transfer

The Utah Geological Survey maintains a web site with a Bluebell home page containing a description of the project, a list of project participants, each of the Quarterly Technical Progress Reports, portions of the Annual Technical Reports with information on where to obtain complete reports, a reference list of all publications that are a direct result of the project, an extensive selected reference list for the Uinta Basin and lacustrine deposits

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Bluebell Project
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worldwide, and daily activity reports of the demonstration wells. The home page address is ***www.ugs.state.ut.us/bluebell.htm***

A paper entitled *Bluebell Field, Uinta Basin: Reservoir Characterization for Improving Well Completion and Oil Recovery,* by Scott L. Montgomery and Craig D. Morgan, was published in the American Association of Petroleum Geologists *Bulletin,* June 1998, v. 82, no. 6, p. 1,113-1,132.

A poster display, *Second Field Demonstration of Completion Techniques in a (DOE Class I) Fluvial-Dominated Deltaic Lacustrine Reservoir, Uinta Basin, Utah,* by Craig D. Morgan, was presented at the AAPG annual convention in Salt Lake City and at the UGS booth at Vernal Petroleum Days in Vernal, Utah, in May 1998.

Bluebell information was also displayed at a conference on fractured reservoirs, co-hosted by the UGS and the Petroleum Technology Transfer Council, Rocky Mountain Region and at the annual meeting of the Interstate Oil and Gas Compact Commission in Salt Lake City. Milind Deo, Ph.D., University of Utah, presented his paper, *Fractured Reservoir Modeling in the Bluebell Field, Uinta Basin, Utah,* at the PTTC conference in Salt Lake City.

A poster display will be presented at the AAPG national meeting in San Antonio, Texas, entitled *Using Detailed Gamma-Ray Log Correlations to Understand Depositional Patterns of a Fluvial-Deltaic Lacustrine Reservoir.* PN

Lower Green River Formation Study
continued from page 1

Reservoirs in the southwest Uinta Basin typically produce at much lower rates than the deeper, often higher pressured north shore reservoirs. As a result, exploration and development in the southwest area have been slow and sporadic until recently. Activity has increased in the Monument Butte area of the southwest Uinta Basin as a result of the Inland Resources Inc./DOE Class I water-flood demonstration project. But the increase in drilling has been confined to the Monument Butte area and has not resulted in any new significant exploration of the southwest region of the Uinta Basin.

An interdisciplinary approach will be used to better characterize the lower Green River reservoirs at the microscopic, well, interwell, unit, and regional scales. Reservoir characterization and geostatistical and numerical simulation modeling can improve primary production and secondary recovery operations and encourage exploration.

Regional correlation of the transgressive-regressive cycles in the subsurface and in outcrop will provide an understanding of the distribution of deltaic deposits and basin evolution through early Green River time. Correlation based on transgressive-regres-

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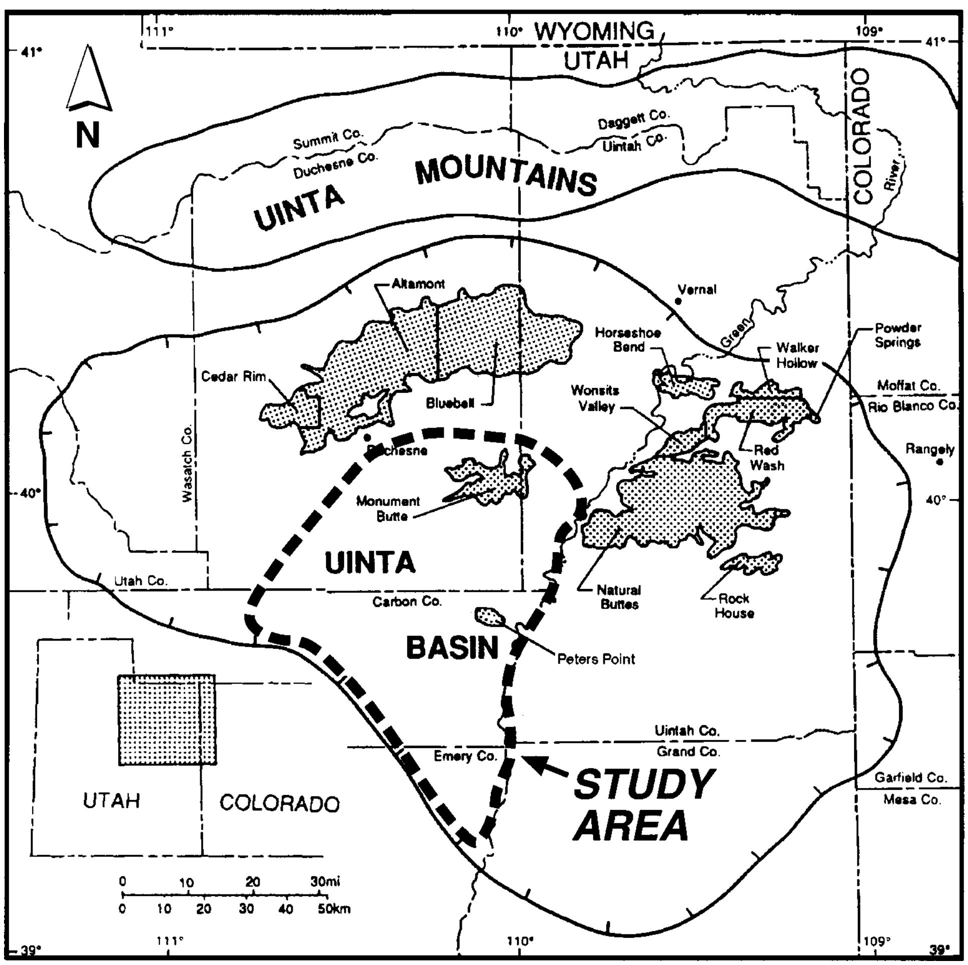

Index map of the Uinta Basin, Utah

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sive cycles will provide a regional stratigraphic framework for the productive reservoirs in the numerous fields and water-flood units; currently, operators use their own terminology for the producing beds, making regional comparisons of productive intervals difficult.

Calculating fracture height, width, and length created by acid-frac treatments and incorporating that data into the reservoir modeling will increase the understanding of fluid flow at the near wellbore scale. Thin section X-ray diffraction and scanning electron microscopy analyses of core and outcrop samples from throughout the south-west Uinta Basin region will yield information about diagenetic histories of the lower Green River reservoirs. Understanding the diagenetic history of the reservoirs can improve exploration efforts and completion techniques.

Geostatistical models will be developed to scale up microscopic, well, and interwell data into unit- and regional-scale numerical simulation models. The geologic model will be presented as both a digital atlas of the region and a field guide (hardcopy) to key exposures analogous to the producing reservoirs. The field guide will allow operators and others to conduct self-guided tours of the outcrop.

The U. S. Department of Energy's National Petroleum Technology Office is funding the study with a grant of $842,000. The UGS and its university and industry partners will use the money to study ways to increase oil production in existing fields and identify prospective areas for new fields in the Uinta Basin. The grant is part of the continuing research being conducted as part of the DOE's Fundamental Geoscience for Reservoir Characterization Program.

The UGS's partners in the study are Milind Deo, Ph.D., University of Utah Department of Chemical and Fuels Engineering; S. Robert Bereskin, Ph.D., Tesseract Corp.; and Inland Resources Inc. and Halliburton Energy Services, Denver.

For additional information, visit our web page at ***http://www.ugs.state.ut.us/greenriv.htm.*** PN

Upcoming Technology Transfer Presentations on DOE Projects

In 1999, the DOE projects described in this issue of ***Petroleum News*** will be featured at the following meetings:

- ***Geological Society of America-Rocky Mountain Section,*** Pocatello, Idaho, April 8 - 10 — Oral presentation on the Ferron Sandstone.
- ***American Association of Petroleum Geologists,*** San Antonio, Texas, April 11 -14 — Booth displays of Ferron, Paradox, Bluebell, Midway-Sunset, and Green River projects; poster presentations of Paradox, Bluebell, and Green River projects.
- ***AAPG Rocky Mountain Section,*** Billings, Montana, August 8 - 11 — Booth displays of Ferron, Paradox, Bluebell, and Green River projects; poster presentations of Paradox, Bluebell, and Green River projects.

Celebration Marks Official Opening of New Sample Library

The Utah Geological Survey in October officially opened its new home for Utah's only repository for geologic samples taken from the outcrop and holes drilled in the search for petroleum and mineral resources in the state. The Sample Library, established in 1951, now occupies a 12,000-square-foot warehouse designed and built to house a collection of cuttings and core samples.

The library currently holds cuttings from more than 3,500 wells and core samples from more than 650 holes drilled in exploration efforts in Utah; a collection of oil samples from all producing formations in the state; representative coal samples from Utah's producing coal mines; dinosaur and other fossil specimens; miscellaneous examples of metallic minerals, industrial rocks and minerals, tar sands, and oil shale; and geologic materials from geothermal wells and surface stratigraphic sections.

The library serves all interested individuals, universities, and companies requiring direct observation of actual samples for their research or investigations. It acts as a repository for irreplaceable geologic samples, and is being used more and more for educational purposes such as training sessions for oil company personnel, college thesis work, and sample evaluations for UGS/industry cooperative projects.

Donations of maps, photos, reports, files, and other geologic materials were received from DeBenneville K. Seeley, Jr., Paul Walton, and Howard Ritzma. Bill Oline donated a rock saw. The Association of Women Geoscientists donated a streambed cutting display used at schools.

Officials with the Utah Department of Natural Resources tour the new Sample Library, with its 18-foot stacks and wide aisles designed for improved storage and retrieval.

For calendar year 1998, the Sample Library hosted five short courses attended by 125 people. In addition, Sample Library staff responded to 184 requests for information on various wells, cuttings, and oil samples. The requests came from industry and consultants (135), colleges and universities (24), the federal government (12), state governments (11), and private citizens (two). In addition, there were 39 requests for paper or digital data associated with geologic samples. The staff also distributed 258 reproductions of core photos.

Donations to the library included 3,868 feet of core from 30 wells and 229,186 feet of cuttings from 68 wells, for a total of 233,054 feet (833 boxes) from 98 wells. Most of the donations are from wells in San Juan County (71); Uintah County sites provided 13 donations; Millard County provided three; Duchesne, Grand, Sanpete, and Wayne Counties provided two each; and Carbon, Garfield, and Summit Counties provided one each.

The following is a breakdown by region of the drill cuttings and core received in 1998 (all locations are relative to the Salt Lake Base Line and Meridian unless identified as being within the Uinta Base Line and Meridian (UBM):

Basin and Range

Equitable Resources Energy Company donated 3,030 feet of drill cuttings from the following well:

Well Name/Number	County	Location
Mamba Federal 31-22	Millard	22-16S-19W

Chevron USA Production Company donated 28,321 feet of drill cuttings from the following wells:

Well Name/Number	County	Location
Sevier Lake Fed 1-29	Millard	29-19S-10W
Blackrock Fed 1-29	Millard	29-20S-9W

Castle Valley

The River Gas Corporation donated drill core from the following well:

Well Name/Number	County	Location
State 1	Carbon	36-14S-9E

Colorado Plateau

Rangeland Petroleum Corporation donated 1,600 feet of drill cuttings from the following well:

Well Name/Number	County	Location
Teasdale 1	Wayne	16-30S-6E

Kaiparowits Basin

Conoco donated wet cuts for the following confidential well:

Well Name/Number	County	Location
Reese Canyon State 32-2	Kane	32-39S-5W

Paradox Basin

The Sherm Wengerd family donated 5,736 feet of drill cuttings from the following wells:

Well Name/Number	County	Location
Amerada 1 Pesco USA	Wayne	19-30S-12E
Buttes 1 Dirty Devil	Garfield	7-31S-13E

Texaco USA donated 39,723 feet of drill cuttings from the following re-entry, multi-lateral wells:

Well Name/Number	County	Location
Aneth Unit F225	San Juan	25-40S-24E
Aneth Unit H325	San Juan	25-40S-24E
Aneth Unit G125	San Juan	25-40S-24E
Aneth Unit E426	San Juan	26-40S-24E
Aneth Unit H125	San Juan	25-40S-24E
Aneth Unit H227	San Juan	27-40S-24E

Uinta Basin

Barrett Resources Corporation donated 14,950 feet of drill cuttings from the following wells:

Well Name/Number	County	Location
Mortensen 3-32A2	Duchesne	32-1S-5W (UBM)
Powell 2-16B1	Duchesne	16-2S-1W (UBM)

CNG Producing donated 39,575 feet of drill cuttings from the following wells:

Well Name/Number	County	Location
State 2-36E	Uintah	36-10S-19E
RBU 6-10F	Uintah	19-10S-20E
RBU 1-10F	Uintah	10-10S-20E
RBU 14-19F	Uintah	19-10S-20E
RBU 15-15F	Uintah	15-10S-20E
RBU 8-22F	Uintah	22-20S-20E
RBU 15-16F	Uintah	16-10S-20E
RBU 11-22F	Uintah	22-20S-20E
RBU 1-21F	Uintah	18-10S-20E
RBU 16-22F	Uintah	22-20S-20E
RBU 15-18F2	Uintah	18-10S-20E

Coastal Oil and Gas donated 3,012 feet of drill cuttings from the following well:

Well Name/Number	County	Location
Iorg 2-10B3	Duchesne	10-2S-3W (UBM)

Quinex Energy Corporation donated 8,080 feet of drill cuttings from the following well:

Well Name/Number	County	Location
John Chasel Ute 3-6A2	Duchesne	6-1S-2W(UBM)

The Sherm Wengerd family donated 1,200 feet of drill cuttings from the following well:

Well Name/Number	County	Location
Guinand USA 1	Uintah	7-8S-25E

Uncompahgre Uplift

Gulf Canada donated drill cuttings from the following confidential well:

Well Name/Number	County	Location
Seismosaur Federal 1	Grand	20-21S-20E

Performance Drilling Motors, Inc. donated 2,610 feet of drill cuttings from the following well:

Well Name/Number	County	Location
Bookcliffs 3	Grand	10-18S-24E

Oil and Gas Activity in 1997 Shows Upswing

Oil and gas activity in Utah increased in 1997 in five of six statistical categories, according to the Utah Division of Oil, Gas and Mining. The only category that did not have better numbers than the previous year was gas production, and that was off by only 1 percent.

The biggest statistical jump was in miles of seismic tests permitted, up 389 percent 1996, when just 19 miles of tests were permitted after 1995's high of 213. In 1997, there were 93 miles permitted, of which 39 miles were completed.

Drilling permits issued increased to 527 in 1997, up 42 percent from the previous year. Drilling commenced, or spudded, showed an increase of 50 percent, with 421 wells. The number of new wells completed or abandoned was up to 382 wells, an increase of 44 percent. That brings to 4,620 the total number of wells capable of producing in Utah, and oil production rose 0.3 percent in 1997, to 19,584,440 barrels (bbls). Gas production was down slightly to 278,088,523 cubic feet (mcf). Of the new wells, 15 were wildcats, 73 were extensions (step-outs), and 294 were development wells.

The deepest well drilled was the GCRL Seismosaur Federal 1 in Grand County, which reached a true vertical depth of 15,482 feet. Most of the new wells -- 339 -- did not extend deeper than 7,000 feet. Thirty-four of the new wells were horizontal.

The most prolific newly completed oil-producing well was the Mortensen 3-32A2 in Duchesne County, with a calculated 24-hour rate of 1,105 bbls. The most productive newly completed gas well was the AL&L 14-33 in Summit County, with a calculated 24 hour rate of 6,606 mcf.

The 1997 oil-producing well with the largest cumulative total was the Anschutz Ranch E. W16-06 in Summit County, which produced 446,862 bbls in 365 days. The gas-producing well with the largest cumulative total was the Anschutz Ranch E. W29-06A, also in Summit County, which produced 13,074,580 mcf in 362 days.

In addition, there were 12 gas processing plants operating as of December 31, 1997, and 120,234,000 gallons of natural gas liquids were produced.

The charts show production figures for gas and oil by county, field, and producer. PN

1997 Oil Production by County

San Juan	35.3%
Duchesne	32.5%
Uintah	16.0%
Summit	14.0%
Others	2.2%

1997 Gas Production by County

Summit	50.4%
Uintah	21.8%
San Juan	8.6%
Carbon	8.2%
Duchesne	7.4%
Others	3.6%

1997 Oil Production by Field

1997 Gas Production by Field

(240 Fields Total)

Greater Aneth	31.6%
Bluebell	14.6%
Anschutz Ranch E	11.7%
Altamont	8.5%
Monument Butte	6.9%
All Other Fields	26.7%

Anschutz Ranch E	49.5%
Natural Buttes	16.6%
Drunkards Wash	7.4%
Lisbon	6.0%
Altamont	3.1%
All Other Fields	17.4%

1997 Oil Production by Operator

127 Oil-Producing Companies

Mobil	21.9%
Coastal	12.6%
Amoco	11.7%
Texaco	8.6%
Inland	6.3%
Others	38.9%

1997 Gas Production by Operator

126 Gas-Producing Companies

Amoco	49.4%
Coastal	11.9%
River Gas	7.7%
UNOCAL	6.0%
CNG	4.0%
Others	21.0%

UGS on the Web

The UGS's home page on the Internet includes a page under the heading **Economic Geology Program,** which describes the UGS/DOE cooperative studies, contains the latest issue of ***Petroleum News,*** and has a link to the DOE web site. Each cooperative study also has its own page. Each page contains a project location map, a description of the project, a list of project participants and their postal addresses and phone numbers, executive summaries from annual reports, all **Quarterly Technical Progress** reports, a reference list of all publications that are a direct result of the project, and a listing of available project publications. The web site addresses are:

UGS home page — http://www.ugs.state.ut.us

Ferron Project — http://www.ugs.state.ut.us/ferron1.htm

Paradox Project — http://www.ugs.state.ut.us/paradox.htm

Bluebell Project — http://www.ugs.state.ut.us/bluebell.htm

Green River Project — http://www.ugs.state.ut.us/greenriver.htm

In addition, the UGS has established a hot link to the **Midway-Sunset Project** web site, which is maintaind by the University of Utah's Energy & Geoscience Institute.

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